Section 5: Scenarios and Sensitivity Analysis

**Disclaimer**: **This draft report was prepared to help the Department of Energy determine the barriers related to the deployment of new nuclear power plants but does not necessarily represent the views or policy of the Department.**

Scenarios and Sensitivity Analysis: Overview

- **Background:** Task 4 of the project involved developing a spreadsheet-based model of the economics and financing of a new nuclear power plant. The model was then used to evaluate a number of different financing structures and risk mitigation strategies. Section 5 reports on the results of these evaluations.

- In performing Task 5, the project team incorporated feedback from industry stakeholders and the financial community to refine a representative base case. Analyses grounded in the base case facilitate our understanding of factors that will determine under what conditions nuclear reactors could be built in the future.

- **Objectives:** The objectives of this task included:

  - Defining a representative base case that reflects a realistic scenario under which new reactors would be developed and financed.

  - Understanding the sensitivity of the base case to changes in key variables, while recognizing uncertainties with respect to cost, timing, financing structure, and output pricing.

  - Investigating potential risk mitigation options, based on the concerns expressed by industry stakeholders and the financial community, and base case sensitivities, to analyze how these risk mitigation techniques might impact values for the key cost elements.

- **Section overview:** This section presents a description of the following:

  - "Base case" financial model assumptions (for four different potential EPC costs for a reactor using a Generation III design).

  - Sensitivity of base case to key variables in the model.

  - Analysis of potential mitigation options.

Base Case Analysis of New Nuclear Power Plants and Sensitivity of Base Case Results to Key Variables

Static Assumptions

• **Technical design basis:** All cases rely on technical performance criteria and requirements that are similar to those of the AP1000, and most values for these factors are based on estimates by Westinghouse, the system designer, for each reactor in a double-reactor plant. This definition of the base case was selected because of the overall economic competitiveness of this technology and because it has been used as the basis for similar analyses. Each AP1000 reactor possesses the following characteristics:

– Nameplate capacity: 1,100 MWe PWR

– Operating life: 40 Years (relicensing after year 40 possible, but not considered here)

– Capital additions: Steam generator replaced in year 20

– Average capacity factor realized: ~90% (~7884 hours per year for the life of the plant, reflecting 54 days of downtime every 540 days for fuel changeout)

– D&D accrual: $465 million over the life of the plant

A range of four EPC (Engineer-Procure-Construct) costs ($1.6, $1.4, $1.2, and $1.0 billion) were used in the base case analysis, reflecting the range of expected EPC costs from the first through later plants. Operating values were held constant across the base case analysis.

• **Financial structure:** Given the magnitude of the potential project and the uncertain and changing nature of today's electricity industry, the project team concluded

that the potential for a non-recourse, or "off balance sheet", project structure was unlikely. While it is possible that a limited recourse structure could emerge through detailed structuring, the project team's objective was to assume a more conservative project structure that directly incorporates the benefits of leverage (i.e., debt), while also reflecting the return criteria of utilities.

The "base case" financial structure includes the following:

– 50 : 50 debt to equity ratio: This ratio is consistent with the capital structure of the major integrated generation / utility companies which would consider adding additional nuclear capacity.

– Leveraged return: The projected internal rate of return (IRR) represents a leveraged return (i.e., return on equity leveraged by the use of debt financing for a portion of the capital cost). The target return for suggesting economic feasibility was set to the 10% – 12% range, *after tax*. This target is at least 200 basis points (2%) over the prevailing weighted average cost of capital in the industry; it represents an appropriate industry target for a leveraged return (assuming key project risks are mitigated to manageable levels).

– Tax loss appetite: Although after-tax cash flows are developed for the base case, the model makes the simplifying assumption that any tax losses typically incurred during the construction phase will be valued on a dollar for dollar basis by the owners.

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Base Case Model Inputs

• Technical / operating assumptions

Major assumptions utilized in the base case include:

– Capital cost: $1.6, $1.4, $1.2, and $1.0 billion EPC cost per 1100 MWe

– Total capitalized cost: $1.624 billion (see Sources and Uses of Funds table on page *5-7*)

– Base construction period: 18 months for development, 36 months for construction, and 6 months for fuel loading & commissioning

– Additional capital costs: In addition to the EPC costs, the following hard costs are assumed:

 • Owner's contingency @ 7.5% of EPC costs

 • Start-up costs of $21.6 million

 • Project development costs of $60.4 million

– Wholesale electricity rate (received): $35 / MWh (3.5¢ / KWh), as base load generation

– Capacity factor: Plant runs at ~90% (~7884 hours per 8760-hour year for the lifetime of the plant)

– Fuel costs: 5 mils (tenths of a cent) per KWh

– Maintenance costs: 5 mils per KWh

– General and administrative costs (including plant labor): $48 million a year, reflecting a 15% saving on current plants due to design efficiencies

– D&D fund: $400 million per 1000 MWe, accrued over 40 years

• Financial assumptions

Financial assumptions utilized in the base case track closely current market conditions and include the following:

– Equity percentage: 50%

– Interest rates: 8% fixed on 20-year loan amortized mortgage style (i.e., level debt service payments). In all likelihood, this type of amortization profile would be accomplished through a series of "mini-perm" financings (in which each financing would amortize for a period and then remaining principal would be refinanced). These financings would have shorter amortization periods, with "bullet" principal payments at the end of each term. The "bullet" amount would be refinanced to achieve a smooth debt service profile over the amortization period. The key exposure in this type of approach would be interest rate risk at each refinancing.

– Depreciation: 15 years for tax purposes (MACRS, an accelerated rate—not straight line)

– Tax rates: 32% net rate for federal, 5% for state, 1% property tax

– Inflation rates: 2% for construction, 1% for fuel

– Debt service reserve (DSR): Set up to address loan coverage ratios, based roughly on one year of interest.

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Base Case Funding Profile

All cases assume that, during the development period, equity dollars will fund project development activities. Upon financial closing, equity and debt dollars will fund construction on approximately a *pro rata* basis. During the operating period, project debt repayments will be satisfied before distributions to equity.
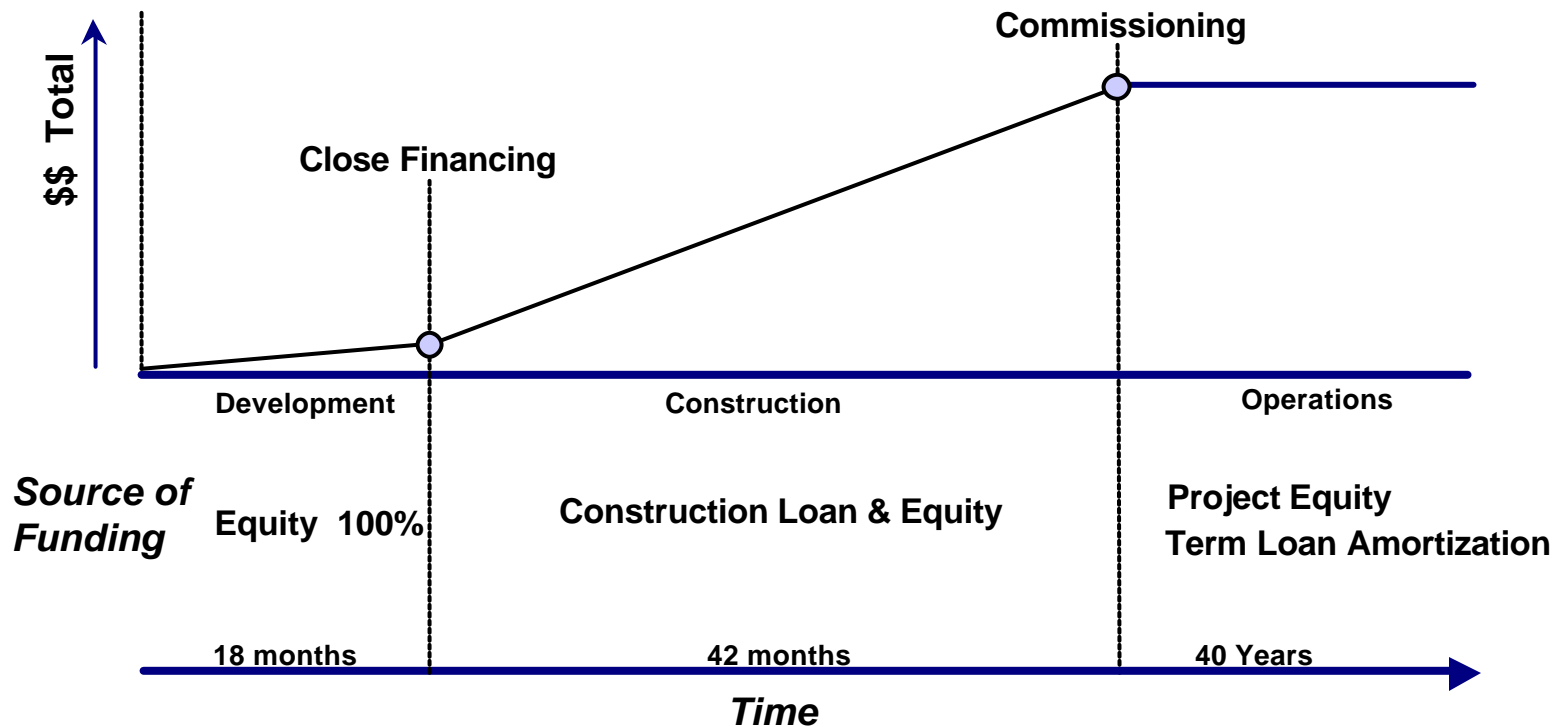
Base Case Sources and Uses of Funds

- The schedule of sources and uses of funds illustrates the capital structure and use of funds in the $1.2 billion EPC cost base case example.

- In this version of the base case, the $1.21 billion (with inflation added) equates to a $1.44 billion facility cost, including:
  - Development costs: $60.4 million
  - Startup costs: $21.6 million
  - Buyer's contingency: $94.6 million (7.5%)

- The gross funding requirements for this plant rise to $1.62 billion when financing costs of nearly $190 million are added.

- The $1.44 billion installed facility cost for this 1100 MWe reactor equates to $1,307 / KWe.

- Similarly, the $1.0 billion EPC cost plant in the base case has a $1.21 billion total facility cost, with a gross funding requirement of about $1.37 billion, which equates to $1,100 / KWe.

EXHIBIT 1: SOURCE AND USES OF FUNDS ($000)
PROJECT: DOE - NE

Project Number: 2 - $1.2B EPC Naked Base Case

USES　　　　　　　　　　　　　　　　　　**SOURCES**

Facility Costs			Gross Funding Requirements	$1,623,809
Development Costs		60,400		
EPC		1,261,130		
Start-Up & Commissioning		21,649		
Contingency		94,585		
Capital Additions		-		
Subtotal		$1,437,763	Senior Debt	$ 812,973
			Senior Debt %	50%
Financing Costs			Equity	$ 810,836
Reimbursement of Development Costs	$	-	Equity %	50%
Interest Capitalized		121,300		
Commitment Fees		7,661		
Closing Cost		16,259		
Capitalized Reserves			Grant Funding	$ -
DSR		40,826	Grant Funding %	0%
O&M/R&R Reserve		-		
Working Capital		-		
Subtotal	$	186,046		
Gross Funding Requirements		**$1,623,809**	**Total Funds Drawn**	**$1,623,809**

Base Case Results: IRRs for Early Plants Fall Below Industry Norms

- **Key results:** Under base case assumptions, most base case financial results fall short of returns that will be needed to justify a compelling business case for early plant orders. Only the $1.0 billion EPC plant in the base case appears to be able to achieve an adequate return.

  - Internal rate of return: The IRR for a new nuclear power plant of this design under base case assumptions ranges from 7.3% to 10.7% for early plants, on an after-tax basis (see page *5-10*), with electricity rates at $35 / MWh. This IRR is somewhat below industry norms of 10% – 12%.

  - Debt service coverage: Minimum debt service coverage ratios under base case conditions fall well below 2x, potentially jeopardizing a project's ability to obtain financing. (Debt service coverage ratios refer to the relationship between cash available to make debt payments and the amount of the debt payment. Lenders in power plant projects usually demand or look for two-fold coverage.)

- **Findings:** Based on our assumed targets for equity returns, the analysis suggests that, under favorable assumptions with regard to capital cost and construction timing, a compelling business case for developing additional nuclear capacity will be difficult to demonstrate for early plants. However, it appears that the gap is relatively small when considering the magnitude of the investment for early orders. Important considerations related to this finding include:

  - Regional differences related to distribution and generation capacity constraints, competition, and market conditions could alter the results to the extent the baseload wholesale rate is greater than $35 / MWh, or 3.5¢ / KWh.

  - Regulatory framework: The changing nature of deregulation at the state and regional level will create additional uncertainty in the projected risk profile of potential developers and their associated rate of return requirements. In fact, some states are not deregulating at all.

  - The base case results can vary significantly, as illustrated by (a) the range of IRR values depending on EPC cost and (b) the range of impact on IRR of changing values for key factors (see following slides).

Sensitivity of Base Case Results for Key Model Variables

A series of sensitivity analyses were conducted that were designed to identify which variables have the most impact on the success of a new power plant project and to assess degree of sensitivity for each variable. These analyses provided feedback about the impact on a key dependent variable, IRR, for changes in EPC cost and certain independent variables, e.g., electricity rate. Later, using the results of the sensitivity analysis, our objective was to identify scenarios (combinations of factors and mitigation measures) that could lead to the construction and operation of new nuclear reactors in the United States.

In developing the base case sensitivity analysis, we identified a number of key questions we wanted to answer:

Illustrative Key Questions for Base Case Sensitivity Analysis:

– How much does capital cost affect IRR?

– Over a range of capital costs, what long-term electricity rate is needed for plants built to achieve an adequate IRR (between 10% and 12%)?

– What is the specific impact on IRR of varying the capacity factor for a plant from 80% – 95%?

To examine the long-run competitiveness of nuclear power, the impact on IRR of changes in several key variables was evaluated for four different plant EPC costs: $1.6 billion, $1.4 billion, $1.2 billion, and $1.0 billion. We chose this set of EPC costs to reflect the likely range for early plants, based on industry comments. Sensitivities were run for the following variables:

– Electricity rate

– Fuel price and fuel efficiency

– Capacity factor

– Delay in plant startup

– Debt : equity ratio

– Interest rates.

Result	Variable	Variable
IRR	EPC cost range: $1.6 B to $1.0 B	Electricity rate: $25 to $45 / MWh
IRR	EPC cost range: $1.6 B to $1.0 B	Fuel price: 4 mils to 6 mils / KWh
IRR	EPC cost range: $1.6 B to $1.0 B	Capacity factor: 80% to 95%
IRR	EPC cost range: $1.6 B to $1.0 B	Startup delay: 6 months speedup to 36 months delay
IRR	EPC cost range: $1.6 B to $1.0 B	Equity funding (v. debt): 40% to 60%
IRR	EPC cost range: $1.6 B to $1.0 B	Interest rate: 6% to 10% (20-year loan)

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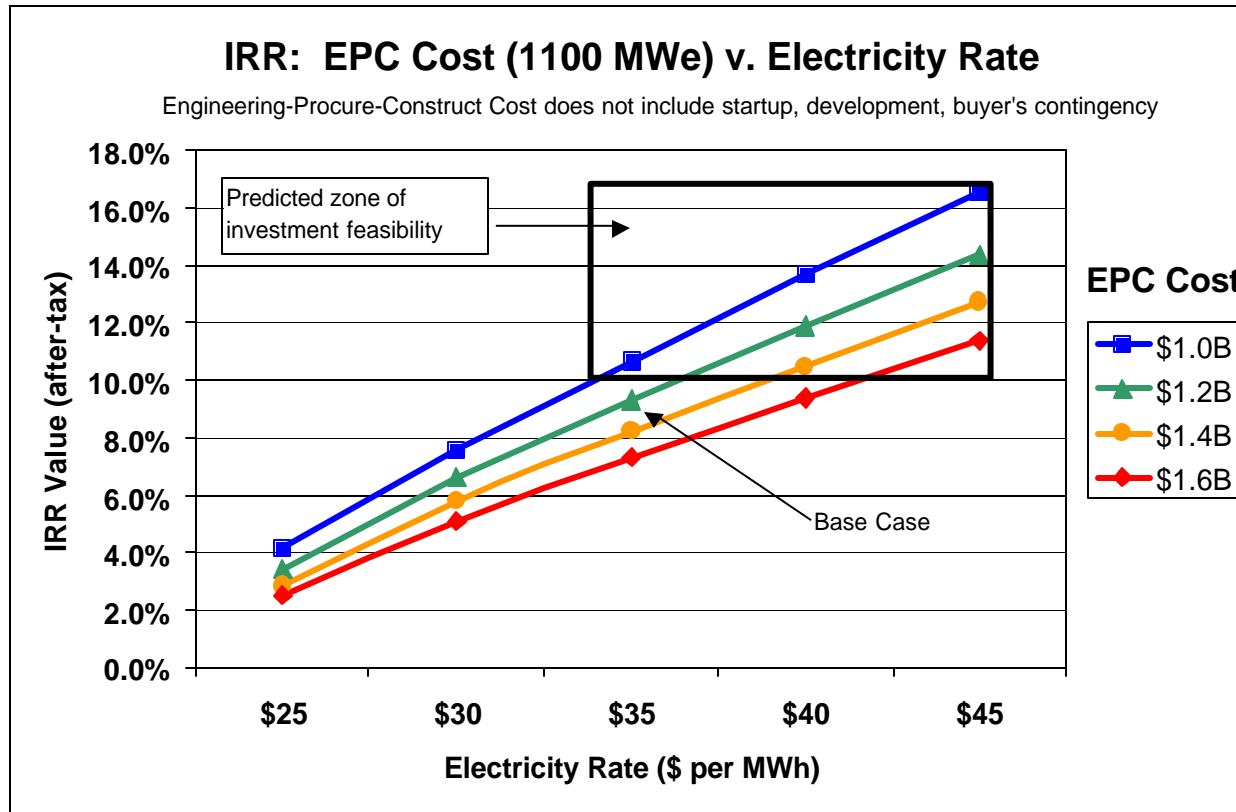# *Sensitivity Analysis: EPC Cost v. Electricity Rate*

- The sensitivity analysis shows that IRR improves as capital costs are reduced. As EPC costs declined over the range evaluated, IRR increased from 7.3% to 9.3% for early plants before reaching 10.7% for a plant with EPC costs of $1.0 billion, with wholesale electricity rates held constant at $35 / MWh.

- When EPC costs were held constant and electricity rates were increased, IRR rose rapidly. Among the major variables, electricity rate is one of the factors IRR is most sensitive to.

- For example, at the $1.2 billion EPC cost, a $2 / MWh change in electricity rate (a 6% change) causes a 1% change in after-tax IRR.

- If wholesale electricity rates are projected at less than $35 / MWh, then early orders of nuclear plants would not likely be an attractive investments. On the other hand, at the highest electricity rates examined, even the most expensive nuclear plant can meet IRR targets.

- Even the highest-cost plant tested ($1.6 billion EPC cost), costing more than $1,700 / KWe, plus financing costs, can achieve an adequate IRR if electricity rates rise sufficiently (i.e, to a point significantly higher than today's market rates, which range widely but are most frequently in the $25 – $45 / MWh range).

- As noted on the Sources and Uses of Funds schedule (page *5-7* of this section), $1.2 billion EPC cost equates to a $1.44 billion facility cost, including inflation plus:
  - Development costs: $60.4 million
  - Startup costs: $21.6 million
  - Buyer's contingency: $94.6 million.

- The $1.44 billion installed facility cost for the second 1100 MWe unit then equates to $1,307 / KWe, and financing costs bring it to $1,475 / KWe.

- The table below is graphed on the next page. It shows that rising electricity rates can create a relatively large zone of investment feasibility.

$ / KWe (1100 MWe)	EPC + (A) + Financing	EPC Cost	Electricity Rate ($ / MWh)				
			$25	**$30**	**$35**	**$40**	**$45**
			IRR ——————————————————→				
$1,943	$2.14B	**$1.6B**	2.5%	5.1%	7.3%	9.4%	**11.4%**
$1,708	$1.88B	**$1.4B**	2.8%	5.8%	8.2%	**10.5%**	**12.7%**
$1,475	$1.62B	**$1.2B**	3.4%	6.6%	9.3%	**11.9%**	**14.4%**
$1,247	$1.37B	**$1.0B**	4.2%	7.6%	**10.7%**	**13.7%**	**16.6%**

(A) Development, Startup, Buyer's Contingency

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Sensitivity Analysis: EPC Cost v. Electricity Rate

Electricity rate is one of the factors that can affect IRR significantly because of the large amount of revenue tied to it.

IRR: EPC Cost (1100 MWe) v. Electricity Rate

Engineering-Procure-Construct Cost does not include startup, development, buyer's contingency

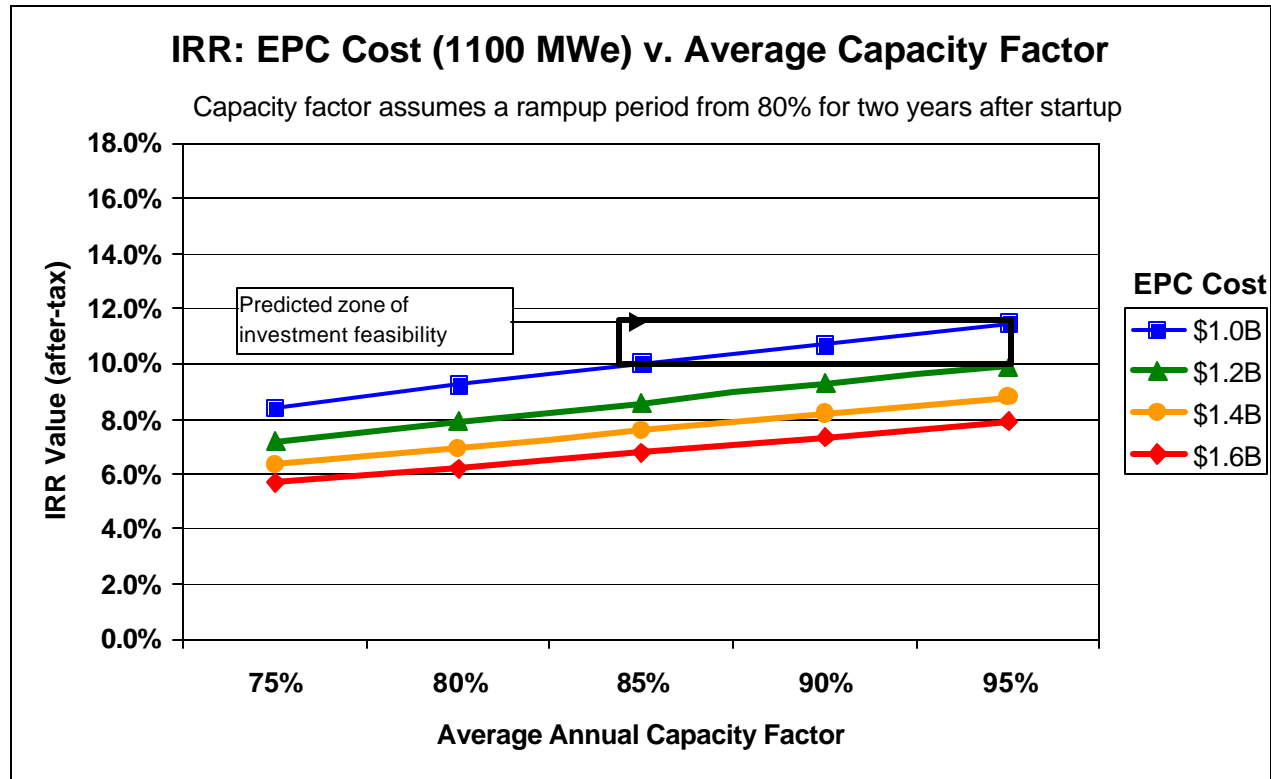# *Sensitivity Analysis: IRR v. Plant Capacity Factor*

- The sensitivity analysis shows that IRR improves somewhat over the range of capital costs tested as capacity utilization rose, but IRR is relatively insensitive to plant capacity factor changes. As a result, capacity factor alone is not enough to boost IRR for early plants into an attractive range.

- For example, for a $1.2 billion EPC cost plant, a seven percentage point increase in capacity factor (an 8% change), causes a 1% improvement in after-tax IRR. At higher EPC costs, the impact is diminished.

- The analysis showed that, for early plants operating in regulated territories, capacity factor increases may give IRR a sufficient boost because returns are more assured than in a market situation.

- Only the plants with an EPC cost of $1.0 billion per reactor appear to be able to achieve the IRR target of 10.0%. The target IRR is reached at a capacity factor of about 85%, five percentage points below the presumed average lifetime capacity factor of a new nuclear power plant.

- This same plant may achieve a 10.7% IRR at the expected 90% capacity factor, as noted in the predicted zone of investment feasibility on the graph on the next page.

$ / KWe (1100 MWe)	EPC + (A) + Financing	**EPC Cost**	**Average Annual Capacity Factor**				
			75%	**80%**	**85%**	**90%**	**95%**
			IRR ⟶				
$1,943	$2.14B	**$1.6B**	5.7%	6.2%	6.8%	7.3%	7.9%
$1,708	$1.88B	**$1.4B**	6.3%	6.9%	7.6%	8.2%	8.8%
$1,475	$1.62B	**$1.2B**	7.2%	7.9%	8.6%	9.3%	9.9%
$1,247	$1.37B	**$1.0B**	8.4%	9.2%	**10.0%**	**10.7%**	**11.5%**

(A) Development, Startup, Buyer's Contingency

Sensitivity Analysis: IRR v. Plant Capacity Factor

Utilities expect that any new plants built would run at better than 90% capacity factor, placing some units with the lowest capital costs in the feasible range.

IRR: EPC Cost (1100 MWe) v. Average Capacity Factor

Capacity factor assumes a rampup period from 80% for two years after startup

EPC Cost
- $1.0B
- $1.2B
- $1.4B
- $1.6B

Predicted zone of investment feasibility

IRR Value (after-tax)

Average Annual Capacity Factor

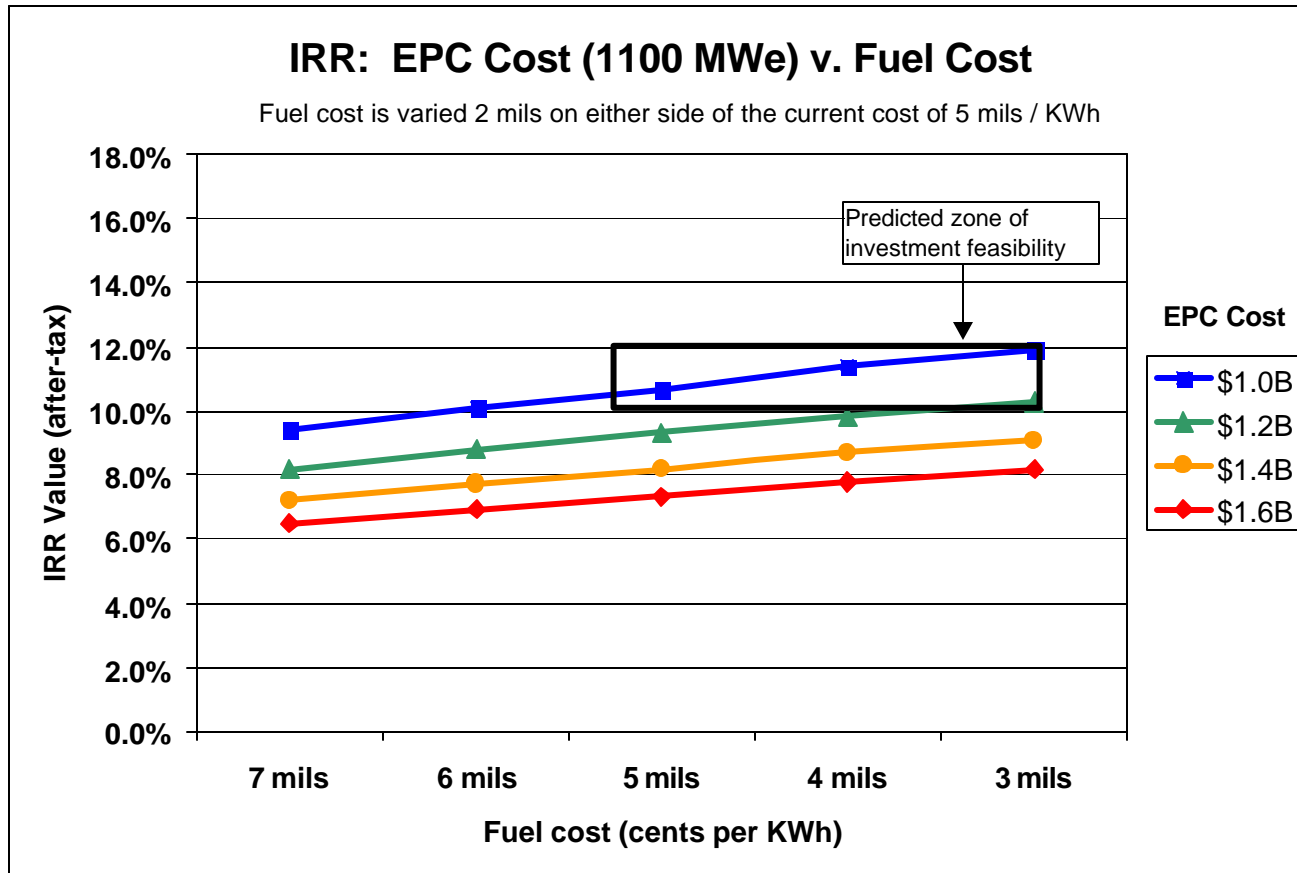## *Sensitivity Analysis: EPC Cost v. Fuel Costs; EPC Cost v. Fuel Efficiency*

• Fuel cost and fuel efficiency are closely matched factors relative to their impact on plant competitiveness.

• The sensitivity analysis shows that after-tax IRR improves only slightly with improvements in fuel cost and fuel efficiency. For example, in the plant with a $1.2 billion EPC cost, a 1% change in IRR required a 2 mil change in fuel cost or fuel efficiency, a 40% change (from 5 mils to 3 mils).

• Notably, however, the insensitivity of IRR to fuel price means that price spikes for nuclear fuel do not shift the IRR on nuclear plants as much as fuel price shifts do for the IRR on gas-fired units.

• Conversely, substantial increases in fuel use efficiency, for example through fuel optimization, do not lead to significant gains in financial returns.

• These insensitivities are reflected in the graph on the next page, in which the lines have a low slope reflective of the insensitivities. The graph illustrates that it is only for the $1.0 billion EPC plant that IRR moves into the zone of investment feasibility with improvements in either fuel cost or fuel efficiency.

$ / KWe (1100 MWe)	EPC + (A) + Financing	EPC Cost	Fuel Costs (Price / KWh)				
			7 mils	6 mils	5 mils	4 mils	3 mils
			IRR				
$1,943	$2.14B	**$1.6B**	6.5%	6.9%	7.3%	7.8%	8.2%
$1,708	$1.88B	**$1.4B**	7.2%	7.7%	8.2%	8.7%	9.1%
$1,475	$1.62B	**$1.2B**	8.2%	8.8%	9.3%	9.8%	**10.3%**
$1,247	$1.37B	**$1.0B**	9.4%	**10.1%**	**10.7%**	**11.4%**	**11.9%**

(A) Development, Startup, Buyer's Contingency

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Sensitivity Analysis: EPC Cost v. Fuel Costs; EPC Cost v. Fuel Efficiency

Varying fuel cost by 2 mils would take a 40% swing in price (from 5 mils to 3 mils), an unlikely change according to interviews with utilities. Fuel costs have leveled off at ~5 mils / KWh since 1990, and the major U.S. suppliers (Canada, Australia, and the USEC warhead spindown program) are stable.

IRR: EPC Cost (1100 MWe) v. Fuel Cost

Fuel cost is varied 2 mils on either side of the current cost of 5 mils / KWh

Predicted zone of investment feasibility

EPC Cost
- $1.0B
- $1.2B
- $1.4B
- $1.6B

IRR Value (after-tax) vs **Fuel cost (cents per KWh)**

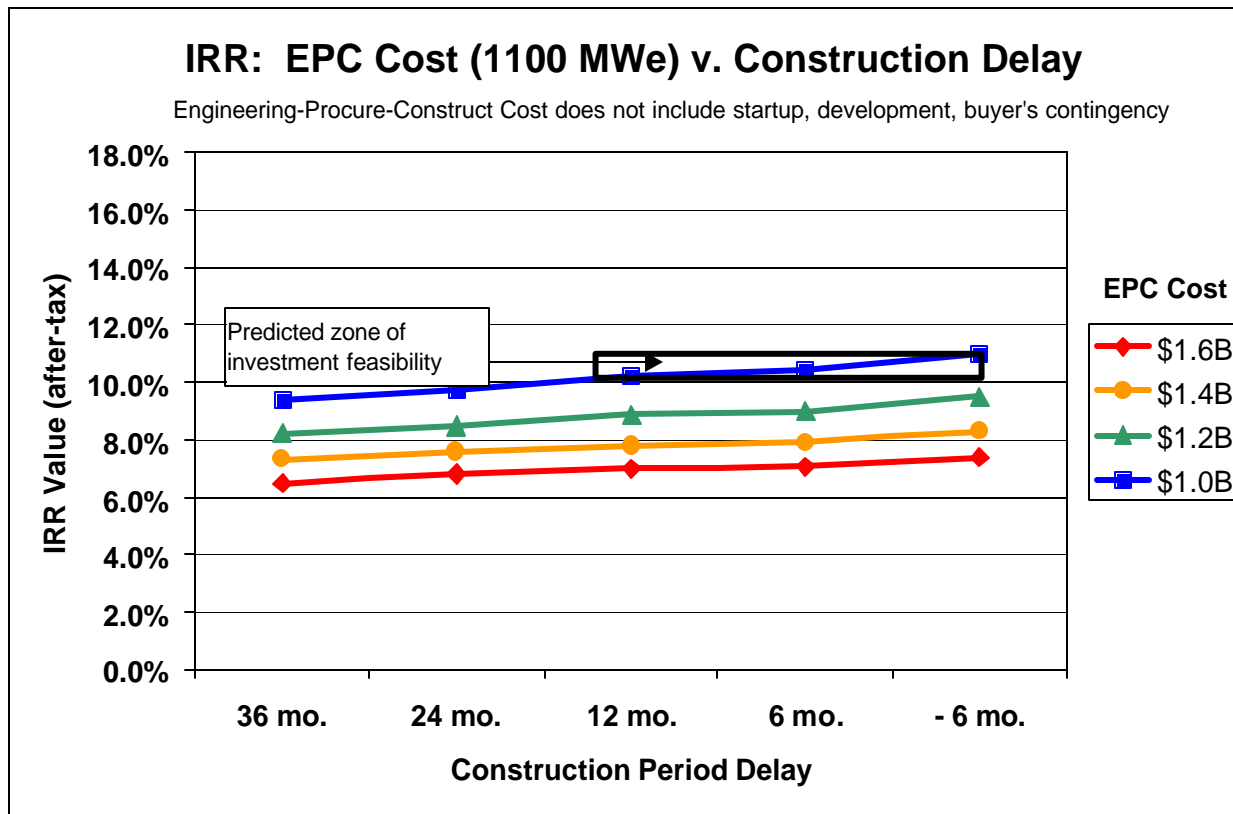## *Sensitivity Analysis: Construction Delay Diminishes the Base Case Further*

- The sensitivity analysis shows that construction delays negatively impact after-tax IRR and plant competitiveness by about half a point in return a year.

- Conversely, reducing construction delays improves IRR, particularly for plants with lower capital costs.

- As seen in the table below and on the graph on the next page, only the $1.0 billion EPC cost plant benefits sufficiently from a 6-month acceleration in construction period to reach the zone of investment feasibility. And, any construction delays penalize the already insufficient rate of return for base case plants and others.

$ / KWe	EPC + (A)		**Construction Period Delay**				
(1100 MWe)	+ Financing	EPC Cost	**36 mo.**	**24 mo.**	**12 mo.**	**6 mo.**	**- 6 mo.**
			IRR ⟶				
$1,943	$2.14B	$1.6B	6.5%	6.8%	7.0%	7.1%	7.4%
$1,708	$1.88B	$1.4B	7.3%	7.6%	7.8%	7.9%	8.3%
$1,475	$1.62B	$1.2B	8.2%	8.5%	8.9%	9.0%	9.5%
$1,247	$1.37B	$1.0B	9.4%	9.8%	**10.2%**	**10.4%**	**11.0%**

(A) Development, Startup, Buyer's Contingency

Sensitivity Analysis: Construction Delay Diminishes the Base Case Further

Construction delay or delay due to commissioning interventions would reduce IRR by about half a point a year.

IRR: EPC Cost (1100 MWe) v. Construction Delay

Engineering-Procure-Construct Cost does not include startup, development, buyer's contingency

EPC Cost

- ◆ $1.6B
- ● $1.4B
- ▲ $1.2B
- ■ $1.0B

Sensitivity Results for Potential Mitigation Solutions

Potential Mitigation Solutions and Their Impacts

As discussed in Section 3, industry and the financial community identified five categories of risks during the interviews and roundtables. These risks can have a negative impact on the likelihood that new nuclear facilities will be built and operated. For each of these risk categories, we evaluated potential techniques for mitigating risks for which existing private sector and government practices are considered to be not completely adequate in improving the chance of a go-forward decision on new nuclear power plants. These potential mitigants, if effective, could be used to help industry overcome the special risks associated with early nuclear units. This part of Section 5 reports on the analysis of the impact of several potential risk mitigation techniques on values for the key cost elements of new nuclear plant projects.

Potential mitigation solutions (discussed more completely in Section 3):

- Interest maintenance facility

- Principal buydown facility

- Equity facility

- Shared development preferred equity facility

- Federal direct loan/loan guarantee

- Tax exempt financing

- Construction cost overrun facility

- Federal power purchase agreement

- Insurance of last resort

Sample Questions:

- What is the quantitative impact of delays in commissioning on the IRR (ranging from 1 – 3 years of delay)?

- What is the impact on IRR of government co-funding (10% – 30%) for construction of first units, for varying capital costs ranging from $1600 / KWe EPC cost to $1000 / KWe EPC cost?

- What is the impact on IRR of an emissions credit within the range of $5 – $25 per ton of CO_2 avoided on a carbon-equivalent basis, which could boost revenue by 5% – 25% overall? (Trades today are being transacted at $1 – $3 per ton of CO_2.)

- What is the impact on interest rates of a government loan guarantee or credit support (e.g., a savings of 100 – 300 basis points, or 1% – 3%)?

- What is the impact on interest rates of tax exempt financing (e.g., a savings of 100 – 300 basis points)?

The next several pages discuss the results of our analysis of the impact on after-tax IRR of several potential risk mitigation solutions. Note that these potential risk mitigation mechanisms are separate from, and in addition to, government efforts to address the "show-stopper" risks discussed earlier in this report.

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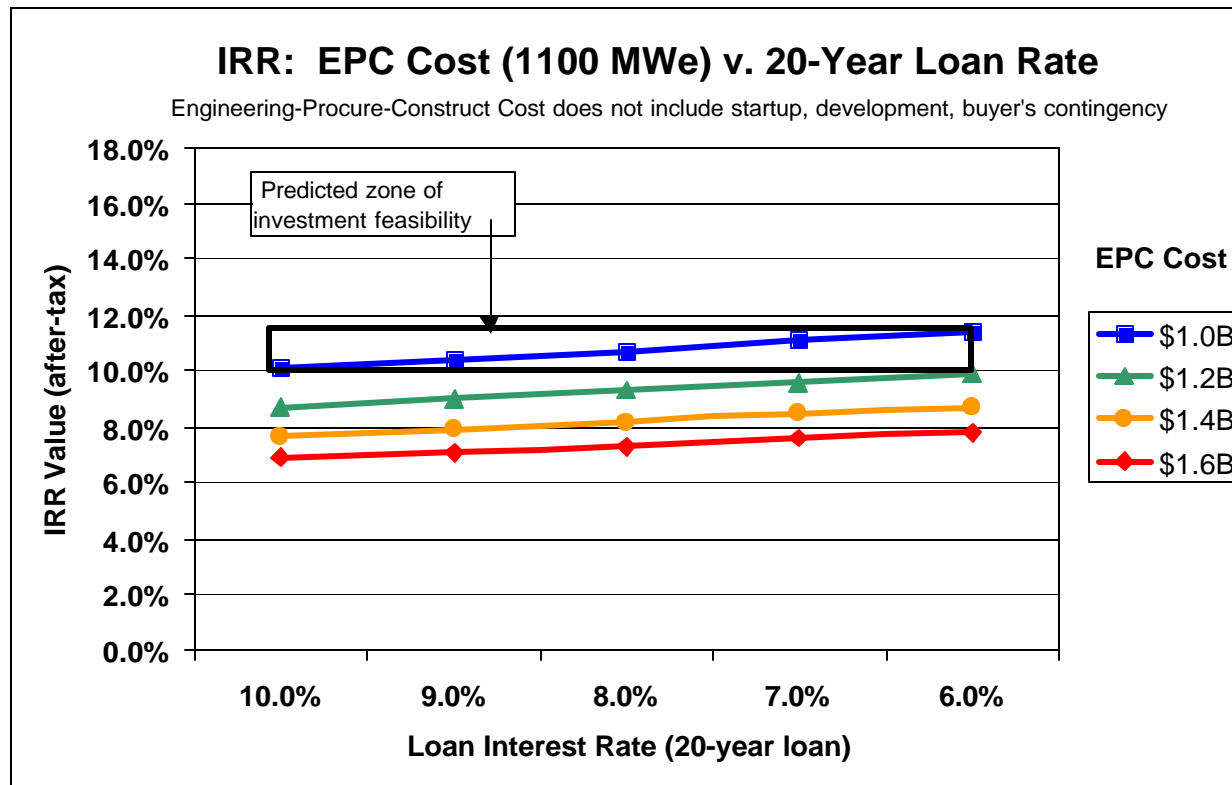# Risk Mitigation: Nuclear Power Viability v. Interest Rate Changes

- A large downward change in interest rate is required to achieve a significant improvement in the viability of new nuclear plants.

- For example, for a $1.2 billion EPC plant operating in an area with $35 / MWh electricity rates, a 1% change in loan interest rates changes IRR by only 25 basis points, or 0.25%.

- Only the lower-cost $1.0 billion EPC plants meet the IRR hurdle rate of 10.0%—and these plants meet the hurdle rate across the range of interests rates tested. The $1.2 billion EPC cost plant could nearly reach the 10% IRR threshold at a 6.0% interest rate.

- For other (earlier) plants, mitigants that affect interest rate are likely to be relatively ineffective because of the insensitivity of plant economics to interest rate improvements.

- Potential mitigants that can have an impact on interest rates are:
  - Government-provided direct loans and loan guarantees.
  - Tax-exempt financing.

$ / KWe (1100 MWe)	EPC + (A) + Financing	EPC Cost	Interest Rate on 20-year loan				
			10.0%	9.0%	8.0%	7.0%	6.0%
			IRR				
$1,943	$2.14B	**$1.6B**	6.9%	7.1%	7.3%	7.6%	7.8%
$1,708	$1.88B	**$1.4B**	7.7%	7.9%	8.2%	8.5%	8.7%
$1,475	$1.62B	**$1.2B**	8.7%	9.0%	9.3%	9.6%	9.9%
$1,247	$1.37B	**$1.0B**	**10.1%**	**10.4%**	**10.7%**	**11.1%**	**11.4%**

(A) Development, Startup, Buyer's Contingency (7.5%)

Risk Mitigation: Nuclear Power Viability v. Interest Rate Changes

Interest rates currently are ~8% for nuclear utilities. Interest backing via government assistance could help lower rates, but today's low interest rates reduce the impact of such backing.

IRR: EPC Cost (1100 MWe) v. 20-Year Loan Rate

Engineering-Procure-Construct Cost does not include startup, development, buyer's contingency

Predicted zone of investment feasibility

EPC Cost
- $1.0B
- $1.2B
- $1.4B
- $1.6B

IRR Value (after-tax)

Loan Interest Rate (20-year loan)

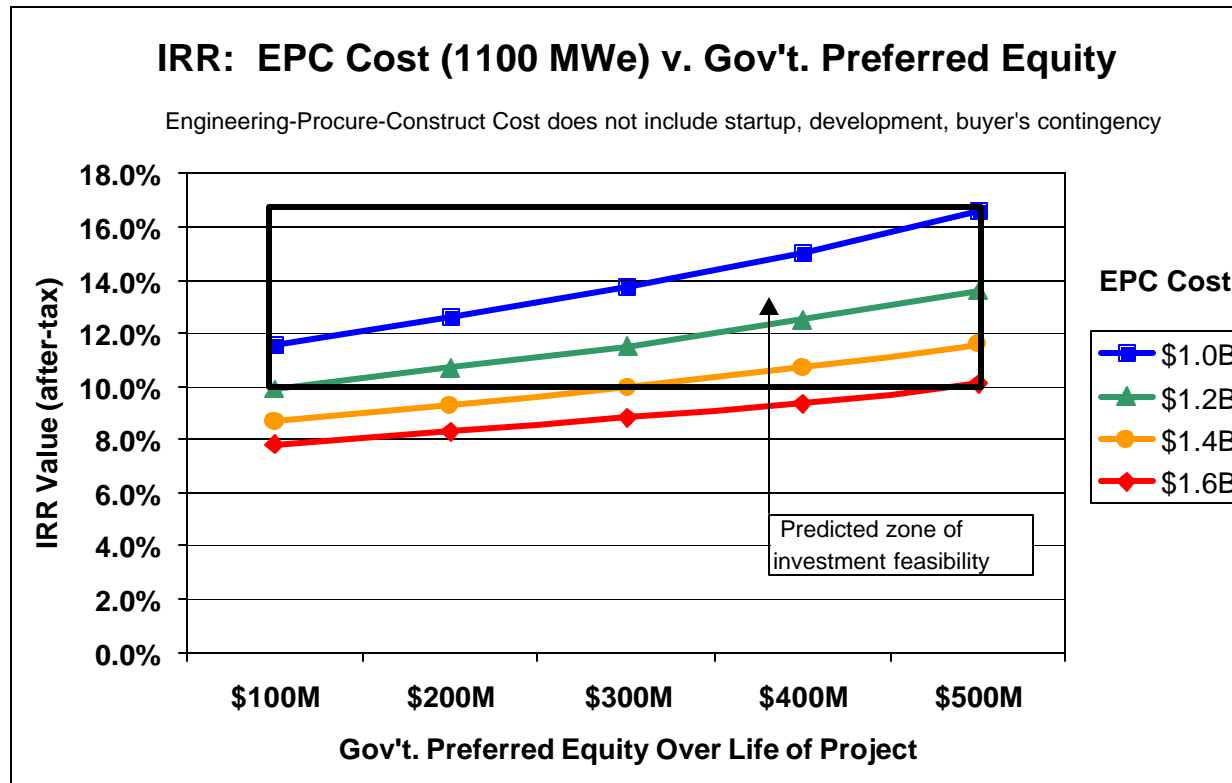# *Risk Mitigation: Nuclear Power Viability v. Government Preferred Equity*

- Government-provided preferred equity is one of the most powerful fools for increasing IRR because of the sensitivity of IRR to debt structure. Government-provided preferred equity thus can be a viable solution in reducing the impact on capital cost of first-time engineering costs and of the high EPC costs of early plants.

- Sensitivity analysis results show that, for a $1.2 billion EPC plant operating with electricity rates at $35 / MWh, the addition of $110 million (just 9% of the $1.2 billion total EPA cost of the plant) in government-provided preferred equity improves IRR by a full 1%.

- In this type of equity arrangement, the position of government-provided funding is subordinate in the project's capital structure to debt repayment, but superior to common equity.

- The government-provided preferred equity would be paid back over time with successful operation of the plant.

- The table below illustrates that such equity is very effective in improving IRR and, therefore, the overall competitiveness of facilities. The chart shows that the addition of significant amounts of government preferred equity could be effective in increasing IRR into the zone of economic feasibility for all plants, even the most expensive plants.

$ / KWe (1100 MWe)	EPC + (A) + Financing	**EPC Cost**	**Government Preferred Equity Amount**				
			$100M	**$200M**	**$300M**	**$400M**	**$500M**
			IRR ⟶				
$1,943	$2.14B	**$1.6B**	7.8%	8.3%	8.8%	9.4%	**10.1%**
$1,708	$1.88B	**$1.4B**	8.7%	9.3%	**10.0%**	**10.7%**	**11.6%**
$1,475	$1.62B	**$1.2B**	9.9%	**10.7%**	**11.5%**	**12.5%**	**13.6%**
$1,247	$1.37B	**$1.0B**	**11.6%**	**12.6%**	**13.7%**	**15.0%**	**16.6%**

(A) Development, Startup, Buyer's Contingency (7.5%)

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Risk Mitigation: Nuclear Power Viability v. Government Preferred Equity

Government preferred equity can improve returns for the full range of EPC costs into the range of economic feasibility. The government-provided preferred equity would be paid back over time with successful operation of the plant.

IRR: EPC Cost (1100 MWe) v. Gov't. Preferred Equity

Engineering-Procure-Construct Cost does not include startup, development, buyer's contingency

EPC Cost
- $1.0B
- $1.2B
- $1.4B
- $1.6B

Predicted zone of investment feasibility

IRR Value (after-tax) — y-axis: 0.0%, 2.0%, 4.0%, 6.0%, 8.0%, 10.0%, 12.0%, 14.0%, 16.0%, 18.0%

Gov't. Preferred Equity Over Life of Project — x-axis: $100M, $200M, $300M, $400M, $500M

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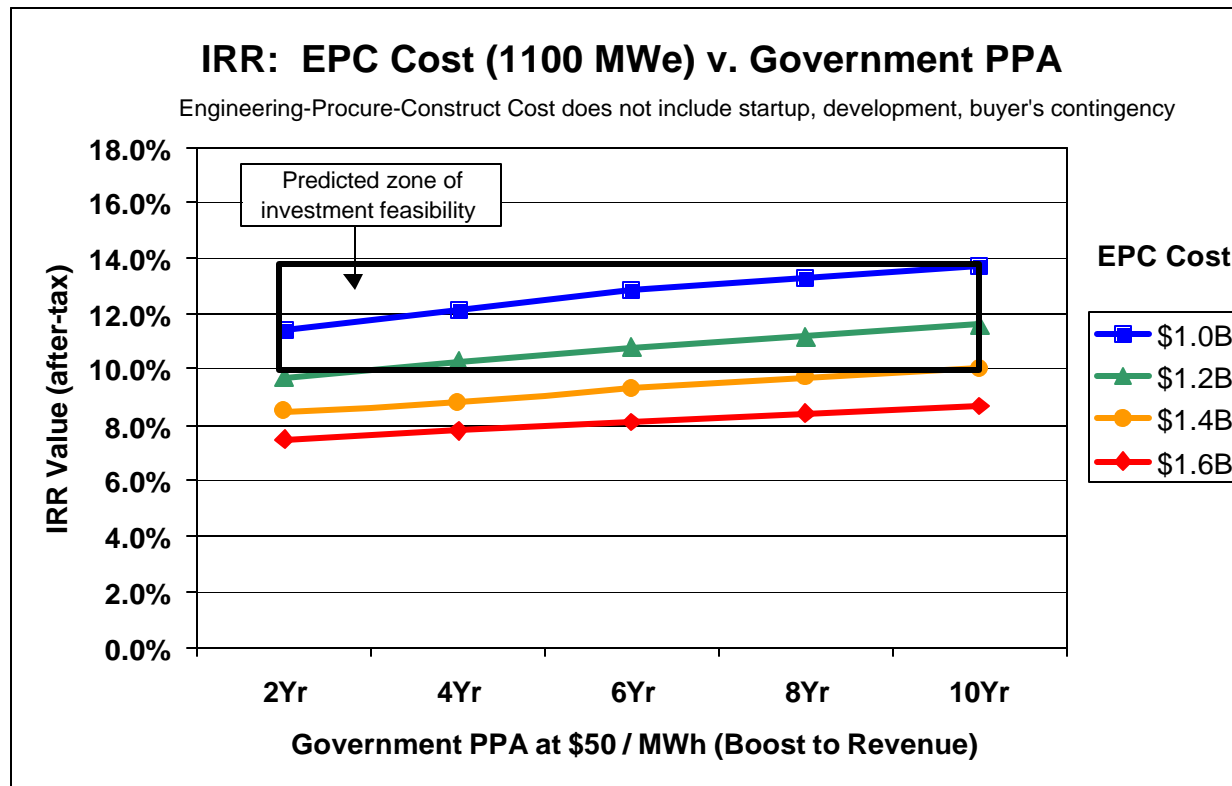# *Risk Mitigation: Nuclear Power Viability v. Government Power Purchase Agreements*

• Power purchase agreements (PPAs) at above-market rates can provide a significant boost to project IRR and, therefore, to a project's overall competitiveness.

• A substantial PPA can bring all but the most expensive EPC plants into the zone of economic feasibility.

• For example, for a $1.2 billion EPC plant operating with electricity rates at $35 / MWh, a PPA that extends for four years at a price of $50 / MWh for 50% of the reactor's production raises IRR by 1%.

• The PPA works in two ways:

– By assuring lenders that a substantial portion of the power produced will be dispatched / purchased.

– By subsidizing the cost of power to the extent that the PPA is priced at above-market rates.

• One important feature of PPAs is that they allow the government to take an annual charge for any losses from reselling power purchased through PPAs, rather than a single, up-front payment. In this way, PPAs allow the government to take advantage of unexpected increases in power prices over time.

$ / KWe	EPC + (A)		Government PPA at $50 / MWh				
(1100 MWe)	+ Financing	**EPC Cost**	**2Yr**	**4Yr**	**6Yr**	**8Yr**	**10Yr**
			IRR ⟶				
$1,943	$2.14B	**$1.6B**	7.5%	7.8%	8.1%	8.4%	8.7%
$1,708	$1.88B	**$1.4B**	8.5%	8.8%	9.3%	9.7%	**10.0%**
$1,475	$1.62B	**$1.2B**	9.7%	**10.3%**	**10.8%**	**11.2%**	**11.6%**
$1,247	$1.37B	**$1.0B**	**11.4%**	**12.1%**	**12.8%**	**13.3%**	**13.7%**

(A) Development, Startup, Buyer's Contingency (7.5%)

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Risk Mitigation: Nuclear Power Viability v. Government Power Purchase Agreements

In a similar fashion to government preferred equity, a power purchase agreement at an elevated price would bolster IRR noticeably. A multi-year arrangement would also spread out the potential government commitment over several budget cycles. The base case involves no power purchase agreement at all.

IRR: EPC Cost (1100 MWe) v. Government PPA

Engineering-Procure-Construct Cost does not include startup, development, buyer's contingency

Government PPA at $50 / MWh (Boost to Revenue)

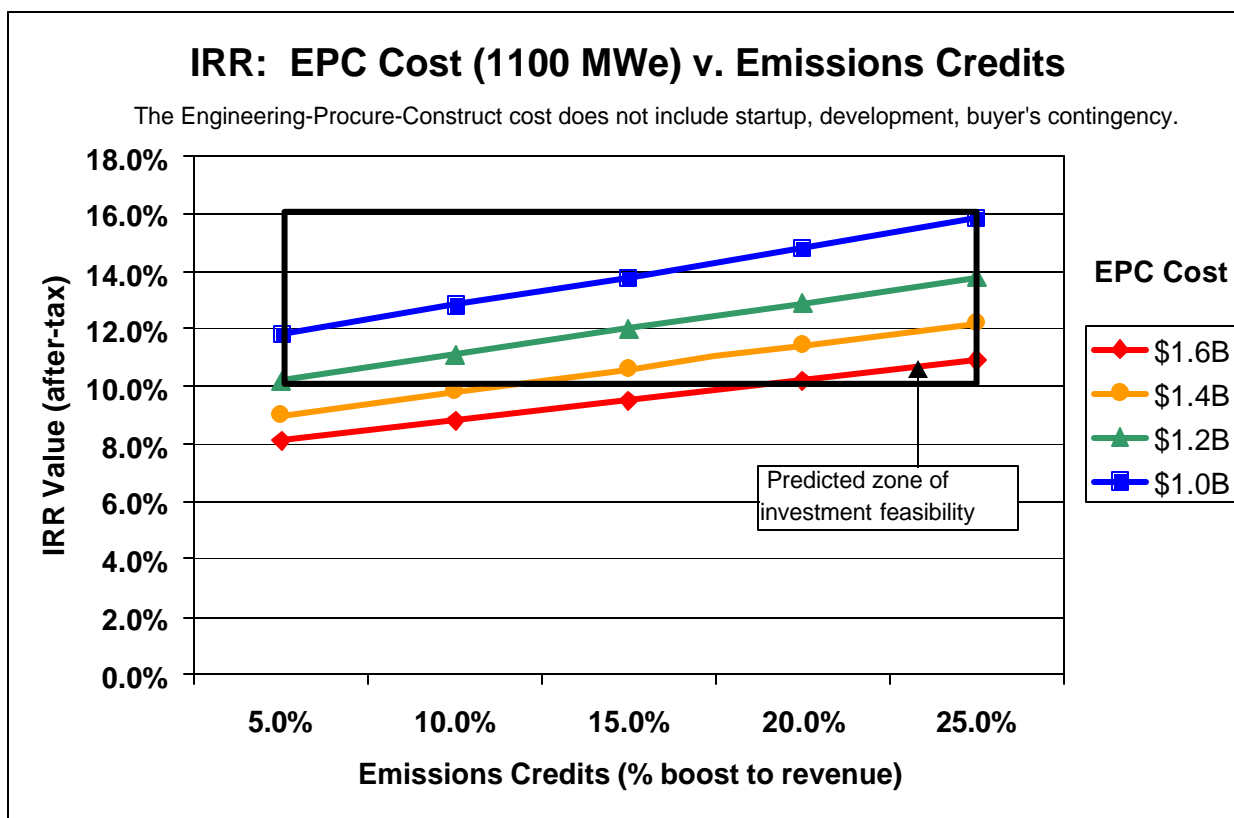# *Risk Mitigation: Nuclear Power Viability v. Emissions Credits*

- Depending on their magnitude, emissions credits for carbon can provide a significant boost to project IRR and, therefore, to a project's overall competitiveness.

- For example, for a $1.2 billion EPC plant operating with electricity rates at $35 / MWh, participation of inherently clean nuclear plants in an emission credit program will provide a 6% boost to revenue and raise IRR by 1%.

- An emissions credit program for carbon involves the establishment of a market for trading carbon-emission credits. Nuclear power could benefit from a potential carbon emissions trading program that rewards low-emitting electricity generation sources because nuclear power does not produce carbon emissions. Nuclear power can most effectively help to reduce the carbon-intensity of the electricity generating segment of the economy in GWe increments.

- As seen on the table below on and in the chart on the next page, even the most expensive new nuclear power plants examined reach the zone of investment feasibility with use of this mitigant.

- Industry executives noted that the inclusion of nuclear power plants in a carbon credit program would be one of the most effective mitigants, yet would have no cost to the government (other than administrative). Existing programs, based in Europe, do not include nuclear power plants.

- An emission credit program in the United States could add costs for fossil sources, but be one of the lowest-cost methods to reduce carbon emissions. Such a program might increase plant revenues ~5% – 10%, if carbon credits were bid at ~$2 – $5 per ton of CO_2. For reference, U.S. emissions of CO_2 were ~1 ton of CO_2 per MWh and totaled >5,500 million tons in 2001, roughly one-third of them from coal-fired power plants (EIA data). Current carbon trades value CO_2 in the $1 – $3 range per ton.

$ / KWe (1100 MWe)	EPC + (A) + Financing	EPC Cost	Emissions Credit (% Boost to Revenue)				
			5%	10%	15%	20%	25%
			IRR →				
$1,943	$2.14B	**$1.6B**	8.1%	8.8%	9.5%	**10.2%**	**10.9%**
$1,708	$1.88B	**$1.4B**	9.0%	9.8%	**10.6%**	**11.4%**	**12.2%**
$1,475	$1.62B	**$1.2B**	**10.2%**	**11.1%**	**12.0%**	**12.9%**	**13.8%**
$1,247	$1.37B	**$1.0B**	**11.8%**	**12.8%**	**13.8%**	**14.8%**	**15.8%**

(A) Development, Startup, Buyer's Contingency (7.5%)

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Risk Mitigation: Nuclear Power Viability v. Emissions Credits

The boost to revenue represented by emissions credits would enhance IRR substantially. Carbon emissions trading could have an effect of a similar magnitude as a government power purchase agreement. Nuclear power plants generated nearly 770 million MWhs in 2001 without producing CO_2; an equivalent volume of electricity from baseload coal-fired plants would have produced about 750 million tons of CO_2, nearly 14% of the U.S. total from all sectors.

IRR: EPC Cost (1100 MWe) v. Emissions Credits

The Engineering-Procure-Construct cost does not include startup, development, buyer's contingency.

Predicted zone of investment feasibility

EPC Cost
- $1.6B
- $1.4B
- $1.2B
- $1.0B

IRR Value (after-tax)

Emissions Credits (% boost to revenue)

Summary of Sensitivity Analysis

Variable	Results for a $1.2 billion EPC plant
EPC capital cost: $1.6 B to $1.0 B	A 1% change in IRR is triggered by a $200 million change in capital cost.
Electricity rate: $25 to $45 / MWh	A $2 change in electricity rate per MWh triggers a 1% change in IRR.
Fuel price: 3 mils to 7 mils / KWh	A 1% change in IRR requires a 2 mil change in fuel cost (a 40% change in uranium fuel prices).
Capacity factor: 80% to 95%	A 1% change in IRR requires a 7-point swing in capacity factor (which is not likely with plants at 90% already).
Startup delay: -6 months to 36 months	A one-year delay erodes IRR by 0.35%, providing the unit does start up.
Interest rate: 6% to 10% (20-year loan)	A 1% move in interest rates alters IRR by 0.3%, assuming a 50 : 50 debt : equity ratio.
Risk Mitigant Mechanism	
Emissions credit (5% - 20% revenue boost)	A 5% boost in revenues from emissions credits improves IRR by nearly 1%; less at higher capital costs.
Power purchase agreement: 2 to 10 years at $50 / MWh for 50% of production (at 90% capacity factor).	With electricity rates at $35 / MWh, a four-year PPA at a price of $50 / MWh for 50% of reactor production raises IRR by 1%.
Government preferred equity	With electricity rates of $35 per MWh, $110 million in preferred equity boosts IRR by 1%.
Government loan support	A 1% cut in interest rates increases IRR by 0.3%, assuming a 50 : 50 debt : equity ratio.

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Impact of Potential Mitigants, as Shown in Sensitivity Analysis

- The table below summarizes the results of several sensitivity analyses that isolated the effect of potential mitigation solutions in order to evaluate their ability to help achieve the IRR threshold and, therefore, competitiveness.

- The table shows that some mitigants work better than others to improve IRR and competitiveness in the base case, which involves the second-of-a-kind plant.

- The table also illustrates that mitigation assistance is necessary to bring power price competitiveness to early units.

- Significantly, the table shows that a plant with a $1.0 billion EPC cost ($1275 / KWe with financing costs) could achieve the IRR threshold without the use of any mitigants, assuming that all base assumptions other than capital cost are held constant and that "show-stopper" risks are resolved, a threshold for new plants.

IRR Threshold	10%	A	B	C	D	E	F	G	H	I
	$1.2 B EPC Base Case	Lower EPC Cost ($1.0B)	Higher EPC Cost ($1.6 B)	Increase Electric Rate to Get 10% IRR	Effect of Interest Rate Buydown to 6%	Effect of Gov't. Preferred Equity	Effect of Gov't. PPA at $50	Effect of Emission Credits	First Unit at $1.6 B EPC with Gov't. Equity	First Unit at $1.6 B EPC with Combo of Factors
EPC Cost ($ billions)	$1.20	**$1.00**	**$1.60**	$1.20	$1.20	$1.20	$1.20	$1.20	**$1.60**	**$1.60**
Fuel Cost (mils / KWh)	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Electricity Rate ($ / MWh)	$35	$35	$35	**$36.40**	$35	$35	$35	$35	$35	$35
Average Capacity Factor	**90%**	**90%**	**90%**	90%	90%	90%	90%	90%	**90%**	**90%**
Debt : Equity Ratio	50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50	50/50
Interest Rate (20-year loan)	8%	8%	8%	8%	**6%**	8%	8%	8%	8%	8%
Gov't Preferred Equity ($ millions)	--	--	--	--	--	$107	--	--	$480	$200
Power Purchase Agreement at $50 / MWh for 50% of production (of 8.67 mm MWh / year, at a 90% capacity factor).	--	--	--	--	--	--	3 years	--	--	10 years
Emission Credit (% boost of revenue)	--	--	--	--	--	--	--	4.0%	--	
After-tax IRR (with tax loss benefit)	9.3%	10.7%	7.3%	10.0%	9.9%	10.0%	10.0%	10.0%	10.0%	10.0%

Impact of Potential Mitigants, as Shown in Sensitivity Analysis

- Capital cost remains the most significant variable in driving electricity price competitiveness and financial return.

- Revenue enhancements, through higher market prices for power, government supported PPAs, or credits tied to output, are also powerful drivers of improved financial returns.

- Lower borrowing costs, on a stand-alone basis, appear to have somewhat less impact on price competitiveness and financial returns. Combined with other mitigants, or under more leveraged capital structures, they are likely to have more impact.

- Fuel prices and plant efficiency are lesser drivers of electricity price competitiveness and financial return.

- As an example of the capability of mitigants to impact the competitiveness of early plants, we used the model to develop a scenario based on a $1.6 billion assumed first-unit EPC cost (i.e., the prospective first new plant using a new design).

- As shown in Column I on the previous slide, the 10.0% hurdle rate for IRR can be achieved if the facility is supported by a set of mitigants, as follows, assuming the plant operates at an average capacity factor of 90%:

  – Provision of $200 million in government "preferred equity".

  – Government purchase of 50% of the plant's production at 5.0¢ / KWh through the use of a power purchase agreement (PPA) for a 10-year period.

- The sensitivity analysis supports the conclusion that industry is not likely to build a first unit without government assistance, because the first unit is unlikely to be competitive in today's market (i.e., its financial performance will fall below IRR hurdle requirements). Other early units will, similarly, require some government assistance to be competitive and to achieve IRR targets.

- Emissions credits could also aid the feasibility of new nuclear units by boosting prospective revenues.

- However, the sensitivity analysis shows that, once "show-stopper" issues are resolved and early units are built, nuclear power is likely to be competitive, particularly if EPC capital costs drop to $1100 / KWe or lower due to learning curve effects or if power prices drift to slightly higher levels.

- As our findings in Section 3 demonstrate, industry appears willing to work with government to overcome the near-term hurdles through the development of risk mitigation mechanisms, particularly if progress is made in removing the "show-stopper" issues.

- The cost to the government of these mitigation mechanisms requires further analysis to determine a range of likely results associated with potential costs.